CHAPTER III.

TAX TREATMENT OF OIL AND GAS VENTURES UNDER THREE TAX REFORM PROPOSALS

The President's recent tax reform proposal and the original Treasury tax reform report proposed several changes in the taxation of the oil and gas industry.

The original Treasury proposal would have completely repealed the provisions for percentage depletion and expensing of intangible drilling costs. Instead, these costs would be recovered under cost depletion, indexed for inflation. The current system of depreciation would be replaced by a new system based on economic lives and indexed for inflation, and the investment tax credit would be repealed. The top corporate and individual rates would be reduced to 33 percent and 35 percent, respectively. The President's proposals subsequently modified the original Treasury proposal to continue expensing of intangible drilling costs, and retained a limited provision for percentage depletion (for stripper wells only). The depreciation system is more generous than originally proposed by the Treasury, but the investment tax credit would still be repealed. In addition, the tax rate cuts remain intact. (Table 4 compares the oil and gas tax changes under current law and these two proposals.)

An example of an oil and gas investment will be used to illustrate each of the proposals. Consider a company that acquires two leaseholds to explore for oil and/or gas properties at a cost of $5,000 per lease. On the first lease, the firm spends $20,000 on drilling costs for wells that prove worthless and are abandoned after two years. The firm spends $70,000 for drilling costs on the second lease for successful (producing) wells. The firm also spends $10,000 on the second lease to equip the well so that the output can be pumped and delivered to purchasers. The investment is summarized in the table below.

	Lease 1	Lease 2
Lease Acquisition	$ 5,000	$ 5,000
Intangible Drilling Costs	20,000	70,000
Lease Equipment Costs	0	10,000
Total Investment	$25,000	$85,000

<u>Current Law</u>. Under current law, the lease acquisition costs for the second (productive) lease would be capitalized and written off over time according to cost depletion (or percentage depletion if that was greater and if the firm was an independent). Since the first lease is considered to be worthless at the end of the second year, all lease acquisition costs would be deducted at that time. The drilling costs for both leases would be allowed as

TABLE 4. TAX REFORM PROVISIONS AFFECTING THE OIL AND GAS INDUSTRY

Type of Cost	Current Law	Treasury Plan	President's Proposal
Lease Acquisition Costs			
Productive Property	Unindexed Cost Depletion	Indexed Cost Depletion	Indexed Cost Depletion
Unproductive	Deducted When Property Abandoned	Deducted When Property Abandoned	Deducted When Property Abandoned
Percentage Depletion	Independents Only a/	Repealed	Independent Stripper Production Only a/
Drilling Costs			
Productive Wells	Expensed b/	Indexed Cost Depletion	Expensed b/
Unproductive Wells On Productive Properties	Expensed	Indexed Cost Depletion	Expensed
Unproductive Wells On Unproductive Properties	Expensed	Deducted When Property Abandoned	Expensed
Depreciable Property	5-year ACRS Depreciation and Investment Tax Credit	18% Declining Balance Depreciation (Indexed), No Investment Tax Credit	33% Declining Balance Depreciation (Indexed), No Investment Tax Credit

SOURCES: Internal Revenue Code; U.S. Department of the Treasury, Tax Reform for Fairness, Simplicity, and Economic Growth (November 1984); and The President's Proposals to the Congress for Fairness, Growth, and Simplicity (May 1985).

a. Independent oil companies are entitled to percentage depletion or cost depletion, whichever is greater. They are limited to percentage depletion on 1,000 barrels per day of production.

b. Integrated companies must amortize 20 percent of drilling costs associated with productive wells over 36 months.

current deductions, although the drilling costs of the second lease would be subject to the 20 percent three-year amortization requirement for integrated companies. (The costs of drilling dry holes would be deducted in full since they are not subject to the 20 percent amortization requirement.) The $10,000 of lease machinery and equipment would be eligible for the investment tax credit and would be depreciated over five years under ACRS.

The Treasury Plan. Treasury I would abolish the current tax provisions for percentage depletion and the expensing of intangible drilling costs. In lieu of these provisions, the plan would require drilling costs and depletable costs to be recovered through indexed cost depletion. This is similar to depletion under current law, except that the depletion deductions would be adjusted by the price level. In this respect (indexing), the Treasury plan is more favorable to taxpayers in the oil and gas industry than current law. Depletable and drilling costs related to properties that proved worthless could only be deducted at the time of abandonment.34/

In the example, the $10,000 in acquisition costs for both leases and the $90,000 of drilling costs would be capitalized. The $5,000 of acquisition costs and $20,000 in drilling costs associated with the unproductive lease would be deducted when that property was abandoned. (This differs from current law that allows all drilling costs to be deducted as incurred.) The $5,000 in acquisition costs and $70,000 in drilling costs for the productive lease would be recovered over time through indexed cost depletion. (Note that any drilling costs for unproductive wells on a property with productive wells would be included in the cost basis for depletion; they would not be immediately written off as under current law unless the property was entirely abandoned.)

The Treasury plan repeals ACRS and the investment tax credit. Depreciable costs would be deducted according to a system of indexed declining-balance depreciation (referred to as the Real Cost Recovery System, RCRS). The Treasury depreciation rates are intended to approximate economic depreciation--the real decline in the value of an asset. In the case of oil and gas machinery and equipment, this would allow 18 percent of the annual indexed balance to be deducted each year. In the example, $1,800 (18 percent of $10,000) would be deductible in the first year,

34. Current law allows drilling costs to be expensed immediately for dry holes. Under the Treasury plan, firms would have to capitalize all drilling costs, but could deduct them when a property (lease) was abandoned as worthless.

leaving a balance of $8,200.35/ If inflation is 5 percent, the balance at the start of the second year is $8,610 (1.05 times $8,200), and that year's depreciation deduction is $1,550 (18 percent of $8,610). This continues for 12 years at which time all the remaining balance of the equipment is written off.36/ The present value (discounted at 10 percent) of depreciation deductions for this class is 83 percent of the asset's cost under RCRS.

The plan would reduce the top statutory tax rate from 46 percent to 33 percent for corporations, and would allow companies to deduct 50 percent of their dividends paid to investors. The top statutory rate for individuals would be reduced from 50 percent to 35 percent. The Treasury plan would also repeal (beginning in 1988) the windfall profit tax, the add-on minimum tax, and the 20 percent amortization requirement for intangible drilling costs.

The President's Plan. The plan set forth in The President's Proposals to the Congress for Fairness, Growth and Simplicity differ significantly from those originally contemplated by the Treasury in its report. The President's proposals retain the current law provisions for the expensing of intangible drilling costs (including the 20 percent amortization requirement for integrated companies) and only partially eliminate the deduction for percentage depletion. In most respects, the President's proposals retain the current law distinctions between integrated and independent producers.37/

The percentage depletion deduction is eliminated, except for wells that produce stripper oil. As under current law, only independent producers would be entitled to percentage depletion. Royalty owners, however, would be denied percentage depletion altogether under the President's proposals. In lieu of percentage depletion, producers would be allowed indexed cost depletion on

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35. This assumes the equipment is used for a full 12 months; a proportionate reduction in depreciation is required if the property is held for less than a full year.

36. The Treasury plan contains seven different depreciation classes with different depreciation rates, depending on the durability of the assets in the class. Short-lived assets have a higher rate, and vice versa. Oil and gas machinery and equipment has been assigned to a class with an annual depreciation rate of 18 percent.

37. These include the 20 percent amortization requirement for intangible drilling costs (of integrated companies), the retention of percentage depletion for independent stripper production, and the reduced windfall profit tax rates for independents.

their undepleted basis in a property.38/ If the current basis in a taxpayers property is now zero, the repeal of percentage depletion would not be compensated for by any future deductions for cost depletion. The repeal of percentage depletion is phased in over a five-year period, with the deduction being reduced by 20 percent each year until 1990 when the allowance is completely eliminated.

The stated rationale for retaining percentage depletion on stripper wells is to provide an incentive for producers to maintain production from wells that would otherwise be uneconomic. This is probably an ineffective (and inefficient) incentive because once a well nears its economic limit (that is, when gross revenue exceeds production costs by only a small amount), the deduction for percentage depletion becomes very small (if not zero) because of the tax code provision that percentage depletion cannot exceed 50 percent of the taxable income of the property.39/ If the taxable income of the property declines to zero (or below), no deduction for percentage depletion is allowed and, therefore, percentage depletion provides very little (if any) incentive to extend the life of a stripper well.40/

The President's proposals would eliminate the investment tax credit and replace the current system of depreciation with a new system referred to as the Capital Cost Recovery System (CCRS). For mining and oil field machinery, this involves a recovery period of six years (instead of the current five). The basis of depreciable assets is indexed so that the deductions under CCRS retain their real value. At a 10 percent interest rate, the present value of depreciation deductions under CCRS

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38. The undepleted basis of a property is its historical cost of acquisition (and investment) reduced by all accumulated deductions for depletion (either cost or percentage) and intangible drilling costs.

39. Section 613A of the Internal Revenue Code limits the deduction for percentage depletion to 50 percent of a taxpayer's income from a property. The code defines income as gross revenue less all production costs, overhead costs, depreciation, and intangible drilling costs.

40. Percentage depletion may offer an incentive to continue production from marginal wells, if the income from those wells is grouped with the income produced by more profitable wells on the same property. The taxable income limitation is figured on a per property basis, not on a per well basis. This still means, however, that the deduction provides no production incentive for a property near its economic limit.

(for six-year property) is 91 percent of an asset's acquisition cost, compared to 84 percent under ACRS.41/ Since CCRS is indexed for inflation and ACRS is not, the comparison of the two depreciation systems is quite sensitive to the expected rate of inflation. At high rates of inflation, CCRS is relatively more generous than ACRS.

As in Treasury I, the President's plan reduces the top corporate tax rate to 33 percent and the top individual tax rate to 35 percent. The plan retains a 10 percent deduction for dividends paid, reduced from 50 percent in the original Treasury proposal. Under current law, the Windfall Profit Tax is not repealed as proposed by the Treasury.42/ The President's proposals also include a "recapture" tax on accelerated depreciation taken since 1981 as a transition provision. This is intended to recoup part of the windfall gain received by firms whose taxes were deferred under ACRS. (Firms would realize a gain on their deferred taxes because they would be repaid at the new lower rate of 33 percent instead of the old 46 percent tax rate.)

The President's plan eliminates the current corporate minimum tax and replaces it with an alternative minimum tax. The alternative tax is computed as 20 percent of a firm's alternative taxable income. Alternative taxable income is defined to include regular taxable income plus certain tax preference items whose aggregate amount exceeds $10,000. Preference items that affect the oil and gas industry are the amount of percentage depletion that exceeds the current basis of the property,43/ and 8 percent of intangible drilling costs expensed in a given year.

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41. These calculations assume an inflation rate of 5 percent and a real return of 5 percent. The ACRS calculation does not include the 50 percent basis adjustment for the investment tax credit. If the value of the investment credit is included, the present value of ACRS is 102 percent under current law.

42. The termination provisions of the windfall profit tax under current law would remain in effect. By the end of 1994, the tax would be completely phased out.

43. This is the rule for properties placed in service prior to January 1, 1986. With respect to properties placed in service after that time, the tax preference amount would be calculated as the difference between percentage depletion and indexed cost depletion.

CHAPTER IV.

COMPARATIVE ANALYSIS OF TAX REFORM PLANS

METHODOLOGY

This study uses two different approaches to analyze the effects of tax reform proposals on the oil and gas extraction industry. The first examines the effect that changes in the tax law would have on sample oil properties with different characteristics. This "micro" approach measures the overall tax burden on oil and gas production by estimating the total taxes a producer is liable to pay over the life of a given property. By discounting back to the present, the total "present value" of tax payments can be calculated. As tax provisions are modified, changes in taxes, internal rates of return, and equivalent oil price levels are calculated. This property-by-property method allows most of the tax provisions that especially affect the oil and gas industry to be taken into account over the entire life of the investment.

The second method of analysis used in this study is the "cost-of-capital" approach. This is more of a "macro" approach since it looks at the oil industry from an aggregate viewpoint and calculates overall tax effects. By making a series of assumptions as to composition of the "representative" oil and gas investment, the cost of capital to the industry and its overall effective tax rate can be calculated. Moreover, since this general methodology can be used to calculate the cost of capital and effective tax rates in other industries, the effects on the oil and gas industry can be compared with those of other industries.

Both these forms of analysis are "partial equilibrium" in the sense that they take no account of the feedback effects that tax changes in other industries might have on the oil and gas sector. These other effects might take the form of changes in interest rates or in greater competition from alternative fuels, such as coal or nuclear power. In fact, these indirect effects may be sufficiently large in the case of sweeping changes in the tax system to outweigh any effects calculated on a partial equilibrium basis.

THE MICRO INVESTMENT MODEL

The micro approach to analyzing oil and gas taxes uses a "discounted cash-flow" (DCF) model to estimate the taxes paid on the income from an oil investment over its life. The oil investor (producer) estimates the revenues and associated costs over the

life of the investment and determines the investment's present value by discounting all revenues and costs back to the present. The discounted present value of the property is the current value that an investor places on all the future net income from the oil investment. The producer will then decide to undertake the investment if it can be acquired (or developed) at a cost that is less than or equal to its present value. (For example, if the present value of an oil well's net after-tax cashflow was $1 million, but its full cost of acquisition and development was only $800,000, the producer would not hesitate to exploit the prospect.) In the DCF model used here, it is assumed that the producer is willing to pay the landowner (mineral rights holder) an amount (the lease bonus) that is exactly equal to the difference between the present value of net cashflow and the cost of development (if that is, drilling costs, machinery and equipment, and geological costs). If the lease bonus calculated in this manner is less than zero (the present value of cashflow is less than the cost of the investment), the property does not get developed because it is not worth anything to the investor.

The structure of the model assumes that there is a fixed supply of land (properties) that has oil-producing potential. If landowners have no alternative use for the properties, they should be willing to lease them to an oil company for any price above zero.44/ That is, they will accept any bonus bid above zero. Assuming that oil companies compete for prospective oil properties, the bonus will be bid up to the point where the producer expects to earn no more than a normal (risk-adjusted) rate of return (the discount rate) after payment to the landowner.

The DCF model is used to estimate the taxes under current law, the Treasury proposal, and the President's proposal for an independent company and an integrated company. Three hypothetical oil properties that differ in their investment and production characteristics are analyzed. Since no two oil properties are the same, these hypothetical prospects do not capture the full range of possible tax outcomes that might arise. They do, however, provide a representation of the possible results that might arise for prospects with differing characteristics.

The production profiles and investment costs of each of the prospects are set forth in Table 5. Their characteristics are as follows:

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44. If they have an alternative use for the property, landowners will demand a minimum bonus that is equal to the value of the property in its most profitable alternative use, such as housing or farming.

TABLE 5. CHARACTERISTICS OF PROPERTIES USED IN DCF MODEL

Producer	Property No. 1	Property No. 2	Property No. 3
Required After-Tax Rate of Return	12%	12%	12%
Required After-Tax Real Return	8%	8%	8%
Probability of Success	50%	60%	20%
Investment Costs ($000)			
Dry wells	2,642.5	564.6	3,500.0
Geological	300.0	100.0	400.0
Development wells (if successful)	6,955.0	1,556.0	8,000.0
Lease equipment/well (if successful)	1,364.0	600.0	1,500.0
Annual Production Costs (Real) (000 bbls)	150.0	114.0	150.0
Royalty Rate	12.5%	12.5%	12.5%
Severance Tax Rate	11.5%	4.6%	4.6%
Field Size (if successful)(000 bbls)	1,517.7	483.0	3,149.5
Production Decline Rate	10.0%	10.0%	8.0%
Oil Tier	3	1	3
WPT Base Price (dollars)	28.00	18.40	28.00
Oil Price Inflation	CBO	CBO	CBO
GNP Price Inflation	4%	4%	4%
Development Time	1988:1	1987:1	1988:1
Time of Peak Production	1989:1	1987:2	1989:1
Peak Production Per Well Per Day	40	15	70
Time Production Starts to Decline	1991:1	1988:2	1991:1

SOURCE: Congressional Budget Office.

Property No. 1. This property is a medium-risk venture that has a probability of success of 50 percent. It has average production and investment costs (relative to the other two properties). This property has lower expected initial oil output than property no. 3, and has a faster production decline rate. Like property no. 3, this property's oil would be considered new oil for purposes of the windfall profit tax. In general, this property could be characterized as a medium-risk medium-payoff prospect, such as a prospect close to an existing oil field.

Property No. 2. This property has a relatively high chance of success--60 percent. It can be developed swiftly, and reaches peak production relatively fast. Its initial production rate (and reserves) are low compared to the other two properties. Production costs are lower in this case than the others, and the costs of dry and producing wells are relatively low. This prospect is classified as tier one (old) oil for purposes of the windfall profit tax. Overall, this prospect is considered a low-risk low-payoff opportunity, such as an extension to an existing property.

Property No. 3. This property can be characterized as a relatively high risk exploratory prospect--its probability of success is only 20 percent. Offsetting this disadvantage is the relatively high production rate per well (if successful) and a low production decline rate. Compared to the other prospects this property has high costs for dry wells--$3.5 million--and also takes a relatively long time to develop and reach peak production. If successful, the output would be considered new oil for purposes of the windfall profit tax. This property has the highest potential payoff of the properties; it also has the biggest chance of failure.

The DCF model assumes that the lease bonus and geological costs are paid up front and that other investment costs occur in future periods. This analysis assumes that these costs are borne on January 1, 1986. The dry hole costs are assumed to occur ratably over the time between when the bonus is paid and when a development decision is made. If (and when) the property proves unsuccessful, the lease bonus and geological costs are deducted at that time, and the costs of the development wells and lease equipment are not incurred. The costs of development wells and lease equipment are assumed to occur at the time development starts if the property is successful.

The discount rate applied to future cash flows is 12 percent--this reflects a real return of 8 percent and an inflation

premium of 4 percent.45/ The rate of expected inflation is assumed to remain a constant 4 percent over the life of the property. The price of oil is assumed to be $26 per barrel for 1986 and 1987; after that it is assumed to rise by 4 percent per year. These assumptions are consistent with CBO's latest economic projections.

The DCF model is structured so that the price of oil and investment costs remain fixed, but the bonus payment to the landowner varies in response to differences in taxation. The full amount of any difference in taxation is assumed to be fully capitalized into the value of the lease bonus payment. This implies that the taxation of domestic oil producers does not affect the domestic price of crude oil, but that changes in taxation are manifested in lower payments to landowners. Higher taxes mean that landowners would be paid less, and vice versa. Note that if the value of the bonus drops below zero because of a change in the tax law, the property will not be developed since it is no longer profitable to do so. This is the primary mechanism by which higher taxes can affect domestic oil production.

The assumption of a fixed oil price is based on the rationale that the price of oil in the United States is determined in world markets and that domestic producers have no control over its level. That is, if domestic producers tried to pass on a tax increase to purchasers in the form of higher prices, purchasers would stop buying from domestic producers and substitute imported oil (at the prevailing world price).

The DCF model measures the effect that changes in taxation are likely to have on prospective oil investments; it does not indicate how taxes would change on past investments. Once an investment has been made (that is, once a well has been drilled), it becomes a sunk cost; at that point, the taxes paid over its life will be a function of actual events, not of assumptions or forecasts. In other words, changing the taxation of income from existing investments does not affect their level, but does affect their realized return. Changing the taxation of oil and gas income affects future oil and gas production primarily

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45. The 8 percent real return used here is higher than the average market real interest rate, reflecting a substantial risk premium associated with oil and gas ventures. In practice, the actual specific risk premium is likely to be related to the riskiness of the investment in question. For simplicity, the real rate has been held constant across the properties considered here.

through its effects on prospective investments.46/ Thus, the DCF model is primarily concerned with the way in which changes in taxation affect the returns to prospective projects rather than already existing ones.

The model assumes that the producer is a corporation that faces the top corporate tax rate of 46 percent. The model incorporates the provisions that affect the determination of corporate taxes, such as depreciation or depletion, as well as the provision for the add-on minimum tax. Although the source of finance (debt or equity) is not explicitly modelled, it is assumed that the real discount rate (8 percent) represents a weighted average of the firm's after-tax marginal cost of funds, from whatever source derived.47/ The model does not take account of taxes paid at the personal level on dividends, interest, or capital gains that might be realized from the investment.

The DCF model can also be used to calculate an equivalent change in the price of oil that would have the same effect on the project's discounted present value as the change in tax policy. This equivalent price change is calculated by replacing the initial bonus payment with the new bonus payment (under the alternative tax system), and solving for the new price of oil that would maintain the required real after-tax return of 8 percent.

The Treasury Proposal. The results from the DCF model under current tax law and the provisions proposed under the original Treasury plan are shown in Table 6. The table summarizes the taxes that would be paid on each property, the required pretax return, the effective tax rate, and the equivalent oil price.48/

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46. Changing the taxation of already existing oil properties affects future investments in those properties (through enhanced recovery techniques, for example) and, to some extent, the timing of production from existing wells. This latter effect, however, is likely to be small relative to effects on prospective investments.

47. In the case of debt, the cost of the funds would reflect the fact that interest is deductible, and the increase in potential bankruptcy costs asssociated wih issuing more debt.

48. The effective tax rate is a summary measure of the overall effect of the tax system on a particular investment. The effective tax rate is defined as the difference between the pretax return and the after-tax return divided by the pretax return. Note that because it is assumed that the after-tax return is fixed, the pretax return must adjust as taxes are changed. That is, if the tax burden is increased, the

For the first property--the medium-risk property--taxes under present law are higher for the integrated company than for the independent company. The present value of total taxes for the integrated company is $426 thousand compared to a negative $118 thousand for the independent company. (The negative taxes mean that the company actually receives a net tax refund from the investment, or is able to offset other income taxes on unrelated income.) The difference in the present value of taxes ($543 thousand) is directly reflected in differences in the amount of the lease bonus that each producer would be willing to pay for the investment.

Since these tax amounts depend on the size of the project, it is useful to compare the effective tax rates, measures of the tax burden standardized for such differences.49/ The effective tax rate for the integrated producer on the first property is 12 percent under current law; the effective tax rate on the independent firm is -4 percent. (By comparison, if the income from the oil properties was taxed in full, the effective tax rate would be the statutory tax rate of 46 percent.) The fact that the effective tax rates are so low reflects certain advantages in the tax law, such as the deduction for intangible drilling costs and the write-off of abandoned properties. The lower tax rate on the independent company is the result of the allowance of percentage depletion only for the independent and the requirement that integrated companies amortize 20 percent of their drilling costs. The present value of cost depletion for the integrated company is $188 thousand compared to $1,356 thousand in percentage depletion for the independent. This advantage is partially offset by the add-on minimum tax, which collects $126 thousand (in present value) from the independent and nothing from the integrated producer.

For both properties 2 and 3, the independent also has a lower tax rate than the integrated producer under current law. On property 2, the integrated producer's tax rate is 42 percent versus 32 percent for the independent; on the third property, the integrated producer's tax rate is 10 percent compared to -4 percent for the independent. The relatively high tax rates on the second property are the result of the high windfall profit tax rates on old oil. (In the other two cases--considered new oil for purposes of the windfall profit tax--the tax imposes no burden

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pretax return must rise in order to maintain the fixed after-tax return.

49. The effective tax rate calculation is on a per dollar of capital basis and therefore does not depend on the scale of the project, but does reflect differences in the composition of investment outlays and revenue flows.